Decision **DRAFT DECISION OF ALJ MALCOLM (Mailed 10/18/2004)**

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking Regarding Policies, Procedures and Incentives for Distributed Generation and Distributed Energy Resources.	Rulemaking 04-03-017 (Filed March 16, 2004)

ORDER TO MODIFY THE SELF GENERATION INCENTIVE PROGRAM AND IMPLEMENT ASSEMBLY BILL 1685

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ORDER TO MODIFY THE SELF GENERATION INCENTIVE PROGRAM AND IMPLEMENT ASSEMBLY BILL 1685

1. Summary

This decision adopts modifications to the Self Generation Incentive Program (SGIP), which provides incentives to businesses and individuals who invest in distributed generation. We implement the provisions of Assembly Bill (AB) 1685, eliminate the maximum percentage payment limits, and reduce the incentive payment for Level 1 projects to $3.00 per watt. The Commission retains the San Diego Regional Energy Office (SDREO) as a non-utility program administrator through 2007. We direct the SGIP program administrators to expand opportunities for public participation in three Working Group activities: developing a declining rebate schedule, developing an exit strategy, and adapting a data release format.

Program costs will continue to be included in utility distribution revenue requirements. The utilities will track these costs in the SGIP memorandum accounts created by Decision (D.) 01-03-073 for recovery in their respective general rate cases.

2. Background

The Commission adopted certain load control and distributed generation initiatives on March 29, 2001, pursuant to AB 970. We authorized a total budget of $137.8 million annually through 2004: $12.8 million for load control, and $125 million for self generation. Under the self generation program adopted in D.01-03-073 and modified in D.02-09-051, certain entities qualify for financial incentives to install three different categories (or levels) of clean and renewable distributed generation used to serve some portion of a customer's onsite load:

Level 1: The lesser of 50% of project costs or $4.50/watt for photovoltaics, wind turbines, and fuel cells operating on renewable fuels;

Level 2: The lesser of 40% of project costs or $2.50/watt for fuel cells operating on non-renewable fuel and utilizing sufficient waste heat recovery,

Level 3:

- 3-R: The lesser of 40% of projects costs or $1.50/watt for microturbines, internal combustion engines, and small gas turbines utilizing renewable fuel.
- 3-N: The lesser of 30% of project costs or $1.00/watt for the above combustion technologies operating on non-renewable fuel, utilizing sufficient waste heat recovery and meeting certain reliability criteria.

The Commission recognized that certain events, such as legislation, market activity, or outcomes of the SGIP program evaluation process, could require modifications to the SGIP during the course of the program. In subsequent orders, the Commission took actions to refine the program, such as adopting a reliability requirement, developing renewable fuel criteria, and increasing the maximum eligible size from 1 MW to 1.5 MW.

On October 12, 2003, the Governor signed AB 1685. The legislation adopts emissions and efficiency requirements that fossil-fueled DG projects must meet in order to be eligible for SGIP rebates, and extends the SGIP through December 31, 2007. The new emissions standards go into effect in two phases: January 1, 2005, and January 1, 2007.

On December 10, 2003, an Administrative Law Judge (ALJ) ruling issued in Rulemaking (R.) 98-07-037 requested comments to the evaluation reports prepared by Itron, as well as on other SGIP-related issues.

On July 9, 2004, the ALJ issued a ruling seeking comments on an Energy Division report that recommended program modifications.

The following organizations responded to one or both ALJ rulings: Pacific Gas & Electric Company (PG&E), Southern California Edison Company (SCE), Southern California Gas Company and San Diego Gas & Electric (Sempra), California Solar Energy Industry Association (CALSEIA), Distributed Energy Strategies (DES),[1] Joint Parties Interested in Distributed Generation[2] (JPIDG), Powerlight Inc. (Powerlight), RWE Scott Solar Inc., MegaWatt Inc., Sacramento Municipal Utility District (SMUD), The City and County of San Francisco (San Francisco), the City of Oakland/Rahus Institute, Prevalent Power, Uni-Solar, Occidental Power, Borrego Solar Systems Inc.,[3] and the California Fairs Alliance of Western Fairs Association (Western /Fairs). This decision resolves the issues addressed in Energy Division's report.

3. Discussion

3.1 Incentive Levels and Size Limits

Under the current structure, incentives are based on a project's generating capacity, measured in watts. The incentive payment is capped at a certain percentage of eligible installed costs. Both the per-watt payment and the percentage cap vary by technology level. For example, a solar panel project receives $4.50 per watt of capacity, up to a maximum of 50% of eligible installed project costs.

The Working Group and program applicants have described the time-consuming process to prepare and review hundreds of pages of itemized project costs to determine whether the costs are eligible under the incentive cap.

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[1] DES represents xxx

[2] JPIDG membership includes Capstone Turbine Corporationems Inc., Chevron Energy Solutions, Cummins Cal-Pacific, Cummins, Inc., next.edge, Inc., Northern Power Systems, Inc., Real Energy Inc., Simax Energy, and Solar Turbines, Inc.

[3] Borrego represents Eco Energies, Inc., Sun Light and Power, Quality Solar, and CC Energy.

Energy Division proposes to remove the maximum percentage cap, and to set incentives according to installed capacity. Energy Division believes this approach would be simpler and less costly for program administrators and applicants, would accelerate the rebate payment process, and provide an incentive for developers to reduce project costs. As an alternative, CALSEIA and Capstone propose to allow applicants to select one of two approaches, either a dollar per watt or percentage cap structure, on a project-by-project basis. We find that it is reasonable to adopt the Energy Division's recommendation and will set incentives according to installed capacity. Streamlining the SGIP program is in the public interest. In addition, we reduce the per-watt incentive, as discussed below.

The Energy Division report also recommends the Commission adopt CALSEIA's proposal to reduce Level 1 incentives from $4.50 per watt to $4.05 per watt. With the exception of SCE, program administrators have exceeded their allocated Level 1 budgets for 2004, and have transferred funds from other categories in an effort to meet Level 1 demand. Both PG&E and SDREO created waiting lists to ensure an orderly reservation process once additional funding becomes available.

While parties agree that the Commission must reduce incentive payments, most believe CALSEIA's proposed incentive payment is too high. To support this claim, PG&E provides an analysis which indicates some projects would actually receive higher incentive payments under the combined effect of eliminating maximum percentage limits and instituting rebates of $4.05 per watt. The Working Group supports reducing Level 1 incentives for wind and solar projects to $3.00 per watt and eliminating the maximum percentage cap, which is the CEC's current model for similar projects. We agree. The demand for incentives in 2004, combined with limited funding available to projects over 30 kW, demonstrates the critical need to limit payments per project to assure the broadest dispersion of Level 1 funds.

Since most program administrators have exhausted their 2004 funds, we believe these changes must occur simultaneously and immediately. As of the effective date of this decision, the new incentive structure for Level 1 wind and solar projects will apply to those projects that have not received a conditional reservation letter, including those projects on waiting lists. Level 1 projects will receive incentive payments of $3.00 per watt. The maximum percentage cap will also apply to Level 1 fuel cell projects. Incentive payments for renewable fuel cells will remain at $4.50 per watt.

PG&E requests that the Commission determine how to treat applications on waiting lists at the end of December 2004. Under current SGIP rules, program administrators must carry over any unused funds to the next program year. The rules also require projects that remain on a waiting list at the end of the year to reapply the following year. As of July 23, 2004, PG&E's waiting list had 109 projects requesting $76.6 million, despite repeated reallocations to Level 1. PG&E closed the waiting list on August 1, 2004. It is unlikely PG&E or SDREO will have funds to carry over to 2005. Under the current budget and program structure, if PG&E were to fund the wait-listed projects immediately with 2005 funds, PG&E could once again be oversubscribed in early 2005.

We agree with PG&E that these vendors should not have to submit new applications on January 1, 2005. A combination of the programmatic changes we adopt today: the reduced incentives, elimination of the maximum cap, declining rebate schedule, as well as the increased budget for Level 1 projects, will ensure funding availability. We direct the Working Group to develop a process whereby applicants whose projects are on waiting lists at the end of the year will not need to reapply in 2005.

Decision 01-03-073 adopted a maximum project capacity size to 1 MW for all eligible technologies, and set a minimum size of 30 KW for Level 1 projects. A subsequent decision increased the project size cap to 1.5 MW, but retained the 1 MW payment cap. Several parties suggest the Commission could increase the maximum capacity requirement again without raising the incentive payment beyond 1 MW. Proposals range from 2MW to 20 MW. DES asserts that allowing larger projects to participate will add substantial new capacity without claiming excessive funds or reducing the number of projects that can participate. PG&E raises concerns over the potential for "free ridership," for example, financially viable large projects that would be constructed without incentives. We adopt Energy Division's proposal to increase maximum eligible capacity size to 5 megawatts, effective January 1, 2005. Increasing capacity size will allow developers, customers, utilities, and ratepayers to receive cost savings achieved by larger projects. However, we will continue to limit incentive payments to 1 MW of capacity. We share PG&E's concern that increasing incentive payments from 1 MW to 5MW would allow only a few projects, particularly Level 3 technologies, to receive incentives before depleting a program administrator's entire annual budget.

3.2 Treatment of Program and Project Data

The scoping memo in this proceeding discusses a number of issues related to DG data collection and dissemination, including but not limited to data collected under the SGIP. Today's decision does not address options to streamline collection and availability of data related to interconnection, net metering, and cost responsibility surcharge exemptions. These issues will be addressed later in the proceeding.

In the meantime, we adopt Energy Division's recommendation to create a data release format that resembles the format used by the California Energy Commission (CEC) Emerging Renewables Incentive Program. Although the categories of data of the two programs may differ to some extent, we direct the Working Group to develop a common format that provides similar project information, including but not limited to:

- Seller, installer, developer, or applicant, as appropriate;
- City and zip code;
- Utility name;
- Technology (including model and manufacturer);
- Capacity size;
- Installed price; and
- Inverter model and manufacturer, where applicable.

The Working Group has already made substantial progress toward releasing this information, as demonstrated by a review of the program administrator websites.

We direct the Working Group to develop and circulate proposed formats for discussion among Working Group members and interested parties. The Working Group may also designate one or more program administrator to confer with interested parties to develop the format. Each program administrator should post the required information to its website within 30 days of the effective date of the decision.

We also direct program administrators to post certain program information to their websites, including the amount of funds reserved, paid, and available in each level, funds transferred between levels, and installed and reserved generating capacity. The format should be consistent among administrators.

3.3 Declining Rebates and Exit Strategy

A report written for the Commission by Itron titled "Third Year Impacts Report," raises concerns regarding the impacts an abrupt termination of the SGIP program would have on markets for renewable and clean DG. Itron recommends the Commission adopt an exit strategy based on a declining incentive structure to ensure a smooth transition to a market no longer supported by SGIP rebates. The Energy Division and parties unanimously support the recommendation.

We agree that a declining incentive structure will gradually reduce the market's reliance on a subsidy. This incentive structure should be predictable and transparent, with a specific schedule, rather than applying program milestones such as dollars expended or capacity installed, we therefore direct the Working Group to develop an exit strategy in which rebates gradually decline to zero at the end of the program, currently December 31, 2007. The Working Group shall file a proposed exit plan, which includes specific calendar dates and a table of incentive levels, within 90 days of the effective date of this order. The declining schedule may vary by technology, if appropriate. The Working Group shall organize at least one open meeting with industry participants and interested parties.

After Commission approval, the program administrators should post the plan elements on their websites and we direct them to include the schedule in the program handbook.

CALSEIA proposes to extend the SGIP through 2014, decrease rebates by 7% annually from 2005 through 2010, and by 20% each year from 2011 through 2014. Neither the Itron nor the Energy Division reports address program extension beyond December 31, 2007. We recognize that market conditions or legislative activity could extend the SGIP beyond the AB 1685 sunset date, which would impact the declining rebate schedule filed by the Working Group. While we do not adopt CALSEIA's proposed extension today, we will consider the merits of the proposal after parties have had an opportunity to review and comment on Itron's Third Year Impacts and Cost Benefit Reports, discussed in Section 4.4 of this decision.

3.4 Program Evaluation and Cost Effectiveness

The Commission is considering several DG-related evaluation activities in this and other proceedings. While parties unanimously support a cost-effectiveness study of the SGIP, others seek clarification regarding the purpose of seemingly duplicative cost benefit work, and whether these activities could be consolidated. We describe the evaluation, cost benefit, and cost effectiveness issues under review.

In D.01-03-073, we directed the program administrators to evaluate program success and conduct load impact studies to verify energy production and system peak demand reduction. As observed by Itron and others, many projects that applied for incentives in 2001 were not completed until 2003 or later. Accordingly, Itron had very little production data available for analysis. With over 72 MW installed to date, the program is now better situated for the monitoring, data collection, and evaluation activities envisioned by D.01-03-073. Itron is scheduled to file the Program Year 2003 evaluation report in

October 2004. We intend to address subsequent evaluation plans in a future decision.

Decision 01-03-073 also directed the Energy Division to retain a consultant to study and develop recommendations concerning cost-effectiveness assumptions used to evaluate energy efficiency, demand response, or distributed generation projects. The firm E3 prepared and submitted a report to the Commission in January 2004. In R.04-04-025, the Commission will consider whether the avoided cost methodology proposed by E3 is suitable to evaluate qualifying facilities, energy efficiency, and DG projects.

In R.04-03-017, we intend to develop an overall DG cost-benefit methodology. We indicated we would, to the extent possible, consider other cost effectiveness tests, such as those described in the E3 report and the Standard Practices Manual. Concurrently, Itron is preparing a report that will discuss cost-benefit models. The report will be issued for comment before the end of the year. Itron's report will focus on whether existing or proposed cost-benefit analysis models could be modified to evaluate the value of DG. The report will also help us develop the framework for an analysis of SGIP cost effectiveness, and to determine whether DG provides significant economic, environmental, or societal benefits, which warrant continued rebates, whether through the SGIP or some other form. Lastly, we anticipate this report will inform the Commission's legislative report on the value of net metering, required by AB 58 and due January 1, 2005.

The August 6, 2004 Assigned Commissioner's Scoping Memo issued in this proceeding directed parties to propose cost-benefit methodologies in testimony due October 4, 2004, scheduled hearings for November 2004 and anticipates a proposed decision on a DG cost-benefit methodology by

February 2005. Because of the timing of the Itron report and its obvious tie-in with the issues scheduled to be addressed in hearings, the ALJ recently rescheduled hearings on cost-benefit issues so the parties and the Commission may consider the findings and conclusions of the Itron report in hearings and a subsequent Commission order.

The Energy Division report suggests that the consultant submit an SGIP cost effectiveness study by the end of 2005. Some parties naturally confuse these two efforts. Ideally, we would adopt a cost benefit methodology prior to an analysis of SGIP cost-effectiveness. However, these two related efforts can be conducted concurrently, and updated as necessary. We intend to use the method proposed in the Itron report, due December 1, 2004, as a proxy for a Commission-approved methodology. This approach will allow Itron to submit an interim SGIP cost-effectiveness report by February 15, 2005, and to update the report in December 2005, if necessary, to reflect the methodology ultimately adopted by the Commission. We intend to proceed to adopt a final cost-benefit methodology following hearings.

3.5 Program Administration Through 2007

Consistent with D.01-03-073, Itron also prepared and submitted a report that compares utility and non-utility program administration. The report did not recommend one approach or the other, concluding that both types of administrators brought strengths and weaknesses to the program.

SDREO’s contract with SDG&E expires on December 31, 2004, which coincides with the end of SGIP adopted in D.01-03-073. Since AB 1685 requires the SGIP to continue through 2007, SDREO seeks to continue SGIP administration in San Diego. SDG&E prefers to perform the administrative function within the utility, and to allow SDREO’s contract to expire.

Energy Division recommends that the Commission continue to retain SDREO to administer the SGIP in SDG&E's service territory through 2007, approve SDREO's request for interval disbursement of program funds from SDG&E, and direct SDG&E to eliminate duplicative administrative functions. Staff recommends SDG&E update its contractual arrangements with SDREO to reflect these provisions.

SDREO asks the Commission to clarify the purpose of third-party administration, asserting that SDG&E duplicates the review and approval functions performed by SDREO on SGIP projects. SDREO contends that these duplicative efforts delay issuance of incentive payments. SDREO believes that under the current contract arrangement, SDREO is not a truly independent, non-utility administrator.

SDG&E replies that the utility, not SDREO, is the entity ultimately held accountable by the Commission. SDG&E points out that Itron's evaluation of utility and non-utility administration concludes that SDREO's administrative costs per kW achieved through the program were almost double of one or more utility administrators. SDG&E seeks utility administration, but at a minimum, requests recovery of utility costs for incremental activities such as interconnection safety, contract management, and responsibility for program administrator expenses.

The interval between issuance of the conditional reservation and the incentive payment is typically 12 months or more. This is due primarily to the amount of time required for project design, construction and installation. SDG&E disburses funds to SDREO based on the amount of incentive payments each month, and posts the amount in a memorandum account. SDG&E argues that ratepayers would shoulder significantly higher costs if the SGIP budget is disbursed to SDREO annually.

PG&E points out that SDREO has provided valuable contributions over the first three program years, and that only three years of the program remain. PG&E recommends that the Commission address larger questions concerning third-party administration of utility programs in other dockets and programs.

SDG&E does not provide an estimate of the incremental costs associated with annual disbursement. The Itron administrator comparison report, as well as the impacts and process reports, do not identify which utility administrator is associated with specific program measures. It is difficult, if not impossible, to truly assess the strengths and weaknesses of the individual administrators. Subsequent reports should clearly identify all program administrators, and associate them with their respective performances. However, we believe the program would be operated more efficiently and at lower cost if SDREO had the fiscal and administrative independence envisioned in D.01-03-073. We adopt SDREO's proposal to receive quarterly dispersals of the annual SGIP budget from SDG&E, beginning January 1, 2005. SDG&E shall file an advice letter to reflect the necessary modifications to the Self-Generation Program Memorandum Account (SGPMA).

We reject SDG&E's argument that the utility should receive additional funds to provide SDREO with interconnection and other utility expertise. Utility program administrators receive internal technical support; SDREO must receive similar treatment.

We direct SDG&E to amend the SGIP administrator contract to provide SDREO with fiscal and administrative autonomy through 2007. SDG&E shall submit the proposed amendments to the Energy Division within 30 days of the effective date of this decision. We direct Energy Division to notify SDG&E and SDREO of any contract deficiencies within 10 days of receiving the proposal.

3.6 AB 1685 Implementation

3.6.1 Program Funding Through 2007

AB 1685 directs the Commission to adopt an incentive program in the same form as existed on January 1, 2004 and provides that the Commission has the flexibility to modify the program.

A December 10, 2003 ALJ Ruling sought comments as to whether the provisions of AB 1685 allow the Commission to modify aspects of the SGIP, including the program budget, funding, cost recovery mechanisms, or eligible technologies.

Parties generally agree that AB 1685 provides the Commission with flexibility to make changes to the SGIP, although CALSEIA and JPIDG believe that AB 1685 likely precludes the Commission from reducing the annual program budget. Current funding is $125 million annually through 2007.

In D.01-03-073, the Commission did not adopt the Office of Ratepayer Advocates (ORA) recommendation to set an annual budget of $300 million for the AB 970 initiatives, preferring to test the programs proposed by the Energy Division prior to expansion. We acknowledged the initiatives could be expanded beyond the existing budget. We also indicated we would consider program expansion and future funding increases, whether from funds made available through legislative action, or via distribution rates. We are now interested in expanding the annual state-wide budget, as ORA recommended, and we will consider this change in this successor docket.

The Reducing Level 1 payments will apply pressure on developers to lower project costs, and will help to preserve near-term program funds.

However, the momentum for renewable capacity suggests that demand will continue to exceed the current annual Level 1 budget allocation. In order to assure the maximum development of viable, cost-effective DG projects, we propose funding levels for the SGIP as follows:

Category	Annual Budget
Level 1	$216,000,000
Level 2	$42,000,000
Level 3	$42,000,000
Total	$300,000,000

We solicit the parties' comments on this matter to be filed no later than December 10, 2004.

3.6.2 Emission and Efficiency Requirements

Currently, the Commission requires a Level 3 applicant to submit a permit to operate or other documentation issued by their local air district, approving the unit for operation. Air permitting requirements vary by location.

The Commission also requires Level 3 projects operating on nonrenewable fuel to meet a cogeneration efficiency of 42.5%, as specified in Pub. Util. Code § 218.5. A unit's anticipated efficiency is calculated as the sum of electricity produced and 50% of utilized output, divided by fuel input, based on the unit's average annual consumption.

Assembly Bill 1685 requires combustion-operated fossil-fueled DG projects to meet statewide emissions criteria to qualify for SGIP incentives. Projects must not emit over 0.14 pounds of nitrogen oxides (NOx) per MWh (ppMWh) as of January 1, 2005. By January 1, 2007, units must reduce emissions to 0.07 ppMWh, and achieve a minimum efficiency of 60%. Efficiency is to be calculated as useful energy output divided by fuel input, based on 100% load.

Units that do not meet the 2007 emissions standard may receive “extra credit” for achieving a higher efficiency rate.

To date, the California Air Resources Board (CARB) has certified just two technologies, microturbines and fuel cells, as able to meet the 2007 air emissions limit.

Energy Division’s report recommends program administrators verify a DG unit’s compliance with AB 1685 in one of two ways. The unit is automatically eligible for the SGIP if it is certified by CARB. If the unit is not certified by CARB, an applicant may demonstrate eligibility through the existing process, by submitting manufacturer emission specifications, a permit to operate, and project-specific efficiency calculations.

The staff proposal is the most practical approach for applicants to demonstrate compliance with AB 1685 compliance until CARB certifies additional technologies. We direct the Working Group to modify the program handbook to reflect the AB 1685 emissions and eligibility requirements, and the options we adopt for demonstrating compliance.

3.7 Participation in the SGIP Working Group

The purpose of the Working Group is to ensure program implementation in accordance with Commission policies. In D.03-08-013, we adopted a process whereby market participants may meet with the Working Group to propose specific program modifications for the Commission’s consideration.

The Energy Division’s report recommended expanding membership in the Working Group’s administrative activities, but has modified its view on the basis of the parties’ comments. Instead, this decision requires program administrators to consult with interested parties in three policy-development areas: developing an exit strategy, a declining rebate schedule, and a common data release format.

3.7.1 Program Eligibility

Decision 01-03-073 prohibited utility distribution companies from receiving SGIP incentives. The Working Group seeks clarification as to which distribution companies are excluded from the program.

We clarify that public and investor-owned gas or electricity distribution utilities which generate or purchase electricity or natural gas for wholesale or retail sales, are not eligible to receive incentives.

4. Other Issues

4.1 Corporate Parent Limits

Powerlight contends that projects located on county fairgrounds should be subject to the annual 1 MW corporate/government parent cap per utility service territory. Powerlight states that the fairgrounds are not independent entities, but are overseen by California's State and County Fairgrounds, the Division of Fairs and Expositions, and the California Construction Authority.

Western Fairs and Vote Solar argue that each county fair is a unique, separate, and self-funded entity similar to a school district. Each has its own board of directors, and different legal structures. Most are District Agricultural Associations, some are non-profits, others are county organizations. None are state agencies. Moreover, Vote Solar states that average project costs for these solar installations are \$4.64 per watt, which is considerably lower than the average SGIP rebate.

DES and JPIDG seek to expand MW eligibility under the parent cap. Capstone questions why the Commission restricts the entities most likely to install DG: a statewide network of grocery stores and other retail chains. We agree that putting caps on funding for government and corporate parents hinder the goal of increasing DG capacity to reduce peak demand, and may inflate project costs to artificially high levels. We do not rule today whether or not county fairgrounds are subject to a cap. Rather, we lift the restrictions that limit funding for the university system, other state agencies, and corporations to 4 MW per year.

4.2 Reservation Requests

CALSEIA suspects that certain project developers submit incentive reservation requests for "phantom" projects, in order to reserve funds for undeveloped future projects. CALSEIA states that these practices allow developers to tie up substantial funding that could be reserved for legitimate projects.

Under current program rules, an applicant must provide proof-of-project documentation within 90 days of receiving a conditional reservation request. A program administrator may grant an extension based on project circumstances.

CALSEIA recommends the Commission adopt additional mechanisms to deter phantom projects, such as requiring a nominal fee when an application is submitted, refundable upon project completion. We are not opposed to such a mechanism, provided it does not place an undue financial burden on smaller projects. We delegate to the Working Group the task of developing appropriate procedural or financial mechanisms to deter inappropriate reservation requests.

5. Comment on Draft Decision

The draft decision of the Administrative Law Judge in this matter was mailed to the parties in accordance with Pub. Util. Code § 311(g)(1) and Rule 77.7

of the Rules of Practice and Procedure. Comments were filed on __________, and reply comments were filed on _________________.

6. Assignment of Proceeding

Michael Peevey is the Assigned Commissioner and Kim Malcolm is the assigned Administrative Law Judge in this proceeding.

Findings of Fact

1. The demand for incentives in 2004, combined with limited funding for projects over 30 kW created a situation where cost-effective DG projects did not receive funding. This limitation on funding for viable projects would be mitigated by reducing the incentive payment levels.

2. Reducing Level 1 incentives for wind and solar projects to $3.00 per watt and eliminating the maximum percentage cap will increase the incentives available for viable projects. The existing $4.50 per watt incentive payment for renewable fuel cells does not need to be changed to address a shortage of funding for such projects.

3. No useful purpose is served by requiring projects on SGIP waiting lists to reapply for funds in subsequent funding cycles.

4. Increasing the maximum eligible capacity size to 5 megawatts, but retaining incentive payments up to 1 megawatt, would promote more cost-effective projects to the benefit of ratepayers and utility operations while maintaining enough funds to provide incentives to a number of viable projects.

5. Developing a data release format that resembles that used by the CEC for its Emerging Renewable Incentives Program and requiring developers to make project information available at their websites would improve the usefulness of information related to DG.

6. An incentive structure that predictably declines over time would promote a smooth transition to a market unsupported by SGIP rebates.

7. Developing a cost-benefit methodology for DG projects will assist in the evaluation of the program and related projects.

8. Existing administration protocols between SDREO and SDG&E are complex and have caused delays in program administration and incentive payments.

9. Providing SDREO more autonomy to administer the SGIP program would promote administrative efficiency and lower program costs.

10. Project proponents may demonstrate air emissions compliance with AB 1685 with a certificate from CARB or by presenting relevant documentation regarding facility operational characteristics.

11. Decision 01-03-073 prohibited utility distribution companies from receiving SGIP incentives.

12. Imposing caps on funding for government agencies and corporate parent companies hinder the goal of increasing DG capacity and may artificially inflate project costs.

Conclusions of Law

1. The SGIP incentives should be reduced for Level 1 wind and solar projects to $3.00 per watt and the maximum percentage cap for such projects should be eliminated. The SGIP incentive payment of $4.50 per watt for renewable fuel cells should be retained.

2. The SGIP rules should be modified to eliminate the requirement that proponents of projects reapply for incentives in the subsequent funding cycle, according to a process developed by the Working Group.

3. The SGIP rules should be modified to increase the maximum eligible capacity size to 5 megawatts, but retain incentive payments only up to 1 megawatt.

4. The data release format should be modified to resemble that used by the CEC for its Emerging Renewable Incentives Program.

5. Program administrators should be required to make project information available at their websites.

6. SGIP incentives should be structured so that they predictably decline over time until the termination date of the program. The Working Group should be directed to develop a plan to that end.

7. The Commission should adopt the cost-benefit methodology proposed by Itron on an interim basis while it considers the matter formally in this docket and until it has issued a final order addressing the matter.

8. Existing administration protocols between SDREO and SDG&E should be modified to provide SDREO with more autonomy to administer the SGIP program through 2007 and according to an amended contract with SDG&E.

9. AB 1685 provides the Commission with flexibility to make changes to the SGIP, including changes in the annual program budget.

10. AB 1685 requires combustion-operated fossil-fueled DG projects to meet specified statewide emissions criteria to qualify for SGIP incentives. The program handbook should reflect these emissions and eligibility requirements and the option for project proponents to certify compliance either with documentation from the California Air Resources Board or by submitting manufacturer emission specifications, a permit to operate, and project-specific efficiency calculations.

11. D.01-03-073 intended that SGIP funds should not be awarded to public or investor-owned gas or electricity distribution utilities that generate or purchase electricity or natural gas for wholesale or retail sales.

12. SGIP rules should be modified to remove the restrictions limiting funding for the California state university system, other state agencies and corporate parents.

O R D E R

IT IS ORDERED that:

1. The SGIP incentives are hereby reduced for Level 1 wind and solar projects to $3.00 per watt and the maximum percentage cap for such projects is hereby eliminated. The SGIP incentive payment of $4.50 per watt for renewable fuel cells is retained.

2. The Working Group shall, within 60 days of the effective date of this order and following consultation with interested parties, develop data release formatting and publication protocols as set forth herein, and implement them within 90 days of the effective date of this order.

3. Program administrators shall post required information at their respective websites within 30 days of the effective date of this order, as set forth herein.

4. The SGIP rules are hereby modified to increase the maximum eligible capacity size to 5 megawatts, except that incentive payments are retained at the 1 megawatt level.

5. The cost-benefit methodology to be proposed by Itron in its December 2004 report shall be applied on an interim basis while the Commission considers the matter formally in this docket and until it has issued a final order addressing the matter. The Assigned Commissioner may rescind this order by ruling and upon

a determination that the Itron methodology is unworkable, unjustified or otherwise unreasonable.

6. The Working Group shall, within 90 days of the effective date of this order and following consultation with interested parties, file a proposal to modify the incentive structure so that incentive amounts decline gradually through the program termination date.

7. SDG&E shall, within 30 days of the effective date of this order, submit to Energy Division, an amended contract with SDREO that reflects changes to the administration protocols between SDREO and SDG&E as described herein.

8. Parties to this proceeding may file comments no later than December 10, 2004 on increasing the SGIP budget to $300 million annually, as described herein.

9. The Working Group shall, within 30 days of the effective date of this order, modify the program handbook to (1) assure a method for certification by project proponents of compliance with the air emissions standards required by AB 1685 as set forth herein, (2) eliminate the requirement that proponents of projects reapply for incentives in the subsequent funding cycle; (3) clarify the program handbook to provide that SGIP funds may not be awarded to public or investor-owned gas or electricity distribution utilities that generate or purchase electricity or natural gas for wholesale or retail sales, (4) remove the annual 4 MW restrictions on funding for the California University system, other state agencies and corporations; and (5) include procedural or financial mechanisms to deter inappropriate reservation requests.

This order is effective today.

Dated _____________________, at San Francisco, California.